The Province of Alberta

PETROLEUM AND NATURAL GAS CONSERVATION BOARD

IN THE MATTER OF THE GAS RESOURCES PRESERVATION ACT

and

IN THE MATTER OF an application by Canadian Delhi Oil, Limited, for a permit authorizing the removal of Natural Gas from the Province of Alberta.

I. N. McKINNON, ESQ. (*Chairman*)
D. P. GOODALL, ESQ.
DR. G. W. GOVIER

DATE 9th May 1951.

VOLUME II.

THE COURT HOUSE,
EDMONTON, ALBERTA.

VOLUME II

May 9th, 1951

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FILING OF EXHIBITS

WITNESSES

VOLUME II

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EXHIBITS

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5(a)	Certificate of Registration of the Canadian Delhi Oil Ltd. under The Companies Act of the Province of Alberta........................	67
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SITTINGS OF THE BOARD AT THE COURT HOUSE, EDMONTON, ALBERTA, AT NINE-THIRTY IN THE MORNING, MAY 9TH, A.D. 1951.

MR. McKINNON: Mr. Porter, we suggest that Mr. Dougherty proceed to explain in full detail the methods and sources of data used in arriving at the estimates of reserves and deliverability for Pincher Creek, Viking-Kinsella, Cessford and Leduc fields. We feel this would be helpful to the Board and others in making a detailed study of exhibits "4" and "4(a)". The Board and Counsel may wish to question Mr.Dougherty in the evidence he gives with regard to those fields, but we agree with Counsel that all other cross-examination in connection with Exhibits "4" and "4(a)" should be postponed until September.

MR. PORTER: Before Mr. Dougherty goes on I think it might be a convenient time to file some exhibits which are purely of a formal nature which I overlooked at the opening, and these perhaps may be treated as one exhibit and filed simply to comply with the requirements of the Statute. They show a list of the officers and Directors of Trans-Canada Pipelines and Canadian Delhi and a Certificate of Registration in the Province and a certified copy of a Resolution authorizing the formation of Canadian Delhi. I tender these now.

THE CHAIRMAN: That will be Exhibit "5".

"OFFICERS AND DIRECTORS OF TRANS-CANADA PIPELINES LTD." and "OFFICERS AND DIRECTORS OF CANADIAN DELHI OIL LTD." and CERTIFIED COPY OF RESOLUTION OF CANADIAN DELHI OIL LTD. and "CERTIFICATE OF REGISTRATION" UNDER THE COMPANIES ACT (ALBERTA) ARE TOGETHER MARKED AS EXHIBIT 5.

MR. SMITH: I wonder if Mr. Porter will tell us who the officers are without having to look at that.

MR. PORTER: There are copies of this available for everyone. I think we may now call Mr. Dougherty.

MR. SMITH: Sir, might I draw the Board's attention and Mr. Porter's attention to one other thing, I wonder if at this time he has got some submission or evidence with respect to Section (3), I think it is of the Act, namely, the applicant is entitled to purchase, is there anything on file?

MR. PORTER: About the possession of gas?

MR. SMITH: Yes.

MR. PORTER: I think Mr. Schultz's testimony covered that, I have no document to prove the possession of gas but I thought Mr. Schultz's testimony cleared that.

MR. McKINNON: Possibly you might file some documents later.

MR. PORTER: Later on unquestionably we will prove it by map but I thought his testimony made it clear, that he was in possession of considerable quantities.

MR. McKINNON: The Board is satisfied.

MR. J. F. DOUGHERTY, having been recalled to the stand on his former oath, testified as follows:

A Shall I proceed?

MR. McKINNON: Yes.

A I wonder if I might, before embarking on a discussion of those four fields, clear up a little matter of the Pendant d'Oreille field in which I checked my notes and find I was off base considerably. It might clear the record before we got into the other fields. If

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A (Cont.) you will refer to page 18 of Volume 1, Census Division 1, dealing with the reverse side of the sheet, the projected performance of the Bow Island Sands. Dr. Govier asked me to explain the difference between columns 9 and 10, since the relationship did not appear to have a constant percentage difference. I suspect that our title, titles, for those columns are not sufficiently clear but in fact column 9 represent the open flow capacity based on well-head conditions, that is the P sub c, the closed-in well-head pressure or reservoir pressure instead of the usual bottom hole pressure. Column 10 represents a parallel delivery capacity curve which initially is the relationship between p sub c squared.minus p sub 613 psia, the whole thing squared; in other words, the well-head working pressure curve with the working pressure at 613 psia.

As we proceed then down through the years, for example, in the sixth year the footnote (C) indicates that delivery pressure is reduced to 413 psia, that is the well-head working pressure, so that there is a continual changing percentage relationship between the open-flow curve at well-head conditions and the well-head working pressure curve for the line pressure or delivery pressure at that particular time so that there is no necessary direct relationship between the two

A (Cont'd) curves , the one the open-flow curve and the other the working pressure curve. I think that perhaps clarifies the situation. I might further add that in checking through our notes I find that the percent of total open-flow capacity for the daily gross production represents averages from the first through the 18 or 19 year of less than 25% of open-flow capacity, about 15% roughly. During the latter years it ranges between 26% and would reach a maximum of about 38% in, say, the 24th year when the wells were in effect floating on that given line pressure.

I might start with the Pincher Creek field, referring to Census Division 2, page 4. Page 4 is entitled "Pincher Creek Field, Estimated Natural Gas Reserves, Rundle Limestone." The form of the exhibit is similar to that previously described for non-associated gas reservoirs. In this case I attempted to divide the reservoir for the termination of effective thicknesses of the Rundle Limestone into two portions as shown on pages 5 and 6 following page 4. These respective maps are entitled "Isopachous Map or Thickness Map of the Gross Gas Porosity, Upper Dents and Upper Porous Zones, Rundle Limestone, Pincher Creek Structure". The following thickness map is for the lower half of the Rundle Limestone, the middle hard crystalline and lower porous zones. That subdivision was made primarily because of our concept that the lower half of the productive section would be closer to the gas-water interface and thinking a given

A (Cont'd) permeability and porosity would tend to have a higher connate water saturation, and the core analysis indicated that there was a lower average porosity in the lower half of the formation. However, in our calculations we weighted the thickness to find the total field, acre feet, as shown on page 4 in the 14th column under "proved" and the 15th column under "probable". The acre feet in line 6, estimated reservoir volume, then is a weighted composite of the planemetered thicknesses on the two thicknesses maps. We had a structure map submitted by the Gulf Oil Corporation and well data which formed the basis for the isopachous maps. This structure map was a combination of interpreted seismic and sub-surface data. You will note that in the ends of the structure we have indicated some "probable" and "possible" areas that cannot be fully defined as "proved" at this time. Primarily the areas south of a seismic fault shown at the very south end of the structure in Township 3 North, Ranges 29 and 29. They may well be productive from their position above the estimated gas-water contact. We are not considering them "proved" however at this time. The determination of the average porosity was carried out in this manner, we did not agree with the Gulf Oil Corporation in their interpretation of the core analysis, primarily because they had weighted down the measured porosities by visual microscopic examination which appeared to us to be a little bit on the hazy side, as to just how well one could eliminate measured data by

A (Cont'd) visual examination of the cores and cuttings. We took the viewpoint rather that both plug cores and hole core analyses and the geological examination probably had, each had its own weight which we could not distinguish so that I rather took an average of those three determinations, saying that each had some merit rather than completely eliminating, as Gulf did, much of the weight of the actual plug core analysis. In that fashion we obtained a weighted average porosity for the upper zones, upper porous, middle hard, and the lower zones, including the lower porous zones, by weighting the porosities determined by the plug cores, the hole cores and the geological examination of the thicknesses involved in each of those determinations for the two wells, Number 1 Pincher Creek and Number 1 Marr. In that fashion for the upper zones, upper porous zones as shown on line 7 of page 4 in column 4 we arrived at 4.95% porosity for the estimated average thickness from the planimetered thickness maps on 258.7 feet. For the lower half of the formation, the middle hard, the crystalline and lower porous zones you will note under line 7, column 9, that the porosity obtained by the weighting was 3.48%. In column 14, line 7, the weighted average for the entire reservoir volume of the two zones we have subdivided is 4.42%. Now, we have made the assumption that since the amount of fracture porosity apparently is limited, although we don't know too well how that situation will be close to the sole fault, that the connate water

A (Cont'd) saturations are going to be higher than assumed by some of the other estimators. We have taken 25% for the upper zones, the upper porous zones and 30.4% for the -- I beg your pardon -- 40% for the middle hard, crystalline and lower porous zones where the porosities and permeabilities are of the intergranular type and are considerably closer to the gas-water interface than the bulk of volume of porous spaces in the upper zones. That results in a weighted average reservoir connate water saturation on our assumption of 30.4%. The pressure factors were taken from the Gulf data and Dr. Leisemer's submission, the pressure recorded on line 9, initial reservoir pressure, pounds per square inch absolute, is 4,943 psia. We have also taken the terminal reservoir pressure as being about 700 pounds per square inch absolute, which gives a percentage recovery factor of about 85% of the gas in place in the reservoir. We, in our experience, find that the majority of gas reservoirs recover somewhere between 80 and 90% of the gas in place, even though the 700 pounds per square inch absolute would seem to be a little high for ordinary calculations. However, the percentage or the quantity of liquids in the gas may reduce the effective flow at that, the usual well-head operating pressure of 700 pounds per square inch absolute in the later years of the life. Bottom hole temperature was obtained from measured data at 191 degrees Fahrenheit. Mr. Leisemer's data indicated that as well as the Gulf. The gradient

A (Cont'd) appeared to be somewhat lower than average but on the order of one degree for 100 feet in depth. We obtained by that gradient a 186° F. which would seem to be in close agreement with Mr. Leisemer's figures.

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A (Cont.) We took the deviation compressibility factors, lines 12 and 13 at initial conditions and at the terminal conditions from Gulf, records of their laboratory analyses re combined fluid for the reservoir. Those factors when multiplied in the usual volumetric formula yielded the figures shown in lines 14, initial gas in place per acre foot Mcf, 383, and remaining gas in place per acre foot Mcf, 55. The multiplication of those respective yields per acre foot by our acre foot volume in line 6 for the various categories, proved, probable and possible yields the respective figures in lines 17 and 18. Total initial gas in place, line 16, and total remaining gas in place at the terminal pressure, the difference between those two quantities, being line 18, the inital recoverable gas to terminal pressure.

We had no figures of cumulative production, although we know there has been some volume utilized in the testing of the wells and production of some of the condensate, but in view of the magnitude of our figures we thought this volume would be more or less negligible.

Next we carry on there with the percentage of so called acid gases, hydrogen sulphide and carbon dioxide, we use a percentage of 5% to be deducted for field and fuel uses, and 25% as the shrinkage losses involved in the processing of the gas. That total percentage becomes very close to what is practical experience in the Barker Creek Dome structure, Pennsylvania limestone, whose gas composition is almost identical to the Pincher Creek

A (Cont.) one, the Pincher Creek gas composition, and they find that 27% is the loss or the amount that is deducted through plant processing, field uses, drilling fuel in their actual operations, so we feel that 30% is in the right order of magnitude so far as service losses are concerned. The deduction of those items from the remaining recoverable gas to terminal pressure, line 20, yields the estimated recoverable gas reserve available for sale at the outlet of the processing plant, line 23, 1,388,969 MMcf proved, 154,341 MMcf probable. The total of those two items is 1,543,310 MMcf. The possible reserve is 61,415 million, or a field total of those categories of 1,604,725 MMcf.

The basic reserve figure that we utilized in the performance, projected performance on the reverse side of Sheet 4 is the total of proved and probable, 1,543,310 MMcf, turning to the performance side of that sheet, the form is similar to the one discussed under the Pendant d'Oreille field. Our basic concepts were that by 1954 the projected datas of the first deliveries to the proposed line, Trans-Canada Pipe Lines Limited, at least ten wells should be completed in Pincher Creek, there being two at present and one drilling. Approximately three a year, plus or minus, wouldn't be too heavy a drilling load. That would give us about ten wells on the average in the year 1954. At the present time the back pressure open flow data isn't too satisfactory on the No. 1 Pincher Creek well and open flow potential of 45 MMcf per day has been determined. That's a natural potential, the well

A (Cont.) hasn't been acidized.

The No. 1 Marr had a 14 million per day open flow potential before acidizing, and something in access of 83 MMcf per day after acidizing. The test data was inconclusive in that for the given flow volumes recorded by Gulf Oil, some of the higher producing rates give less pressure drop than lower producing rates, which would indicate that the points are not stablized and that the influence of the fluids in the well bore may be yielding too great a pressure drop for the flow volume. We find in Gulf of Texas that in higher condensate reservoirs that the back pressure method failed to give too consistent a result due to the combination of fuild in the hole and in the stream as well as the inability to pin down the friction factors at high velocities. If some of the points were extrapolated in the normal manner the capacity of the produced gas would in effect be infinite, and to our minds would indicate that the delivery capacity is far in access of anything that we have utilized or that Gulf is considering. It would be limited only by the volume of gas that could be produced through that particular size casing under the differential imposed upon the gross reservoir.

We have used the 83 million flow for our calculations, and you will note that we have indicated at the top of column 9 on the reverse side of Sheet 4 that we consider that the estimated minimum total open flow capacities that will be

A (Cont.) developed if the Marr No. 1 should be increased in capacity from 14 million to 83 million by acidizing, the 45 million per day volume of the No. 1 Pincher Creek might be substantially in excess of 100 MMcf per day. We also on a percentage basis in our thinking refer to the Barker Creek field, again, this is about the same depth and same composition gas and roughly the same pressure and find that Mr. Schellhardt who is the co-author of the Bureau of Mines Bulletin No. 7, Engineer for the El Paso Natural Gas Company has interpreted many of those wells as having potentials in excess of 150 MMcf per day and that future wells and these present wells in Pincher Creek may be in that order of magnitude, but it will take considerably more work to pin it down more closely than the assumptions we have made today.

We utilized the .68 slope shown on the test data on the No. 1 Marr before acidizing, although in all the other studies we have used the .85 slope. We are not clear in our own minds as to just what the influence of the fluids in the well bore and the friction factors will have on that back pressure slope. But, in any event, using that back pressure slope, the pressure drops for a given flow rate are higher than would be the case if it were a .85 slope, which it may be actually if adequate tests could be made. So that our decline in open flow capacity may be a little high for the given decline in reservoir pressure using this in flow of .68. We converted that 83 MMcf per day open flow,

A (Cont.) minimum open flow for the average well to a well-head working pressure open flow by paralleling the test data of the No. 1 Marr, both on the bottom hole back pressure curve and the well head working pressure curve and arrived at an average well-head capacity of 63 MMcf per day for the shut-in well-head pressure of 3,249 pounds per square inch absolute at the well-head. We then constructed the back pressure curve, well-head working pressure curve. In which P sub c squared minus P sub 813 pounds per square inch squared as being our estimated line working pressure or the back pressure against the well-head, and utilize that curve in the calculations under column 10, which would give the total delivery capacity for the number of wells shown in column 7 through the years, as a function of the pressure differential between the then existing reservoir well-head pressure and 813 pounds per square inch absolute well-head working pressure. That would mean that at all times we have a very substantial cushion of delivery capacity. If we wished to drop the well-head working pressure below 813 pounds. You will note on our chart that we haven't dropped the well-head working pressure below 813 pounds over the entire 25 year period. With the compressor facilities which will undoubtedly be present at the extraction plants, the well-head working pressures could be reduced substantially. We feel these are minimum delivery capacities and minimum flow rates, but just what the operator will do is something we can't predict. We suspect that their desire to

A (Cont.) obtain pay-out on substantial investment will require them to drill perhaps more wells than we have shown and produce at higher rates.

The net effect of these calculations would be to indicate that over a 25 year period the daily average net gas delivery shown in column 5 would be around 120 MMcf per day, roughly. The daily gross average production required to yield that daily net average would be approximately 171 MMcf per day.

We are well aware that some of the test data that Gulf is now accumulating are showing some difficulties with the formations of hydrates and the need for reducing the well-head working pressure, at least, having a considerable part of the pressure drop occur well down in the well bore, but it is our experience in similar reservoirs that those are features which merely take the expenditure of some time and capital to overcome, and we don't feel that there is any great danger involved in finding them unable to produce these reservoirs at high rates.

The drilling of the twenty wells would be on the 14,000 odd acres we have set up as being proved. We think the resultant spacing would be economical, and possibly in all respects it could be closer if the company decided to produce a reservoir at higher rates.

I believe that covers our basic method in the Pincher Creek calculations.

I wish to refer now to the Cessford area, I believe that's Census Division 5, pages 4 through 11. However, we will refer first to the map shown

A (Cont.) on pages 6, 7, 8 and 9, beginning with page 4 in Division 5, and at this stage, the map Exhibit 6, 7, 8 and 9. Reference to the maps will indicate that we have roughly divided the area into two parts as designated on pages 4 and 5 as being respectively the Cessford-Delhi area, which is the south-eastern group of wells and their respective areas, and centered in some cases by the Canadian Delhi wells Nos. 1, 2, 3 and 4, and then we considered separately, what we call the Cessford-Sunnynook field, which includes the areas controlled by the Amerada wells, that's in the north half of the map Exhibit 6, 7 and 9.

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A (Cont'd) Those two wells are the Amerada-Stanolind Well and the Amerada-Crown Well. The Crown Well is now being completed, testing gas very recently.

We have in our files the complete reports of the Delhi Oil Corporation put out by the Denton-Spencer Company on the drilling and completion of the Delhi Wells and as much data as Mr. Raborn was able to give me along with the efforts of Mr.Beach, from the Amerada people on their wells, including electrical logs and some slight core data and test data. In addition we have a seismic map of Delhi Oil Limited covering the Delhi-Cessford area and a portion of the Amerada-Sunnynook area; and they have formed along with the thickness data from the electrical logs and the cores, our basis for attempting to delineate the areas we have designated as proved, probable or possible.

In no case have we shown any reserves, even in the possible category, the isolated possible areas in which wells have not been drilled. They are seismic prospects and are areas of possible development in which we haven't shown any reserves. Our reserves are limited to those areas surrounding completed wells.

Referring to Page 4 of Census Division 5, the Delhi portion of the Cessford area, we have estimated reserves for the Viking Sand: approximate depth 2,650 feet. The Upper Blairmore Sand: average depth approximately 3,150 feet. Then there is the Second Blairmore Sand which is a stray that popped in above the so-called Upper Blairmore Sand in one

A (Cont'd) well, the No.3 Cessford Well of Canadian-Delhi shown on Page 8 -- or, Map 8; and finally we have the Basal Cretaceous Sand -- in this case called Sunburst -- probably really a Sunburst equivalent -- due to its proximity to the Princess area where the Sunburst is developed. That sand occurs at depths on the average of 3,400 feet, plus and minus.

We don't have any core data on the Viking Sand in either the Sunnynook or the Delhi part of the Cessford area. We did have core data from the Princess area and from the Viking-Kinsella, and from the Sibbald field and the Oyen prospect. Those latter two areas are northeast of Cessford in Census Division 5,near the Saskatchewan line.

That data would indicate that 20% average porosity was not unduly optomistic or pessimistic and we so used that percent, and estimated interstitial water saturation of 35%, based primarily on the Princess area data from the California-Standard Company and our interpretation of certain Viking-Kinsella data. The bottom hole pressure data at initial conditions, we used the gradient determined by the bottom hole pressure test data on the Sunburst Well, the No. 1 Cessford of Canadian-Delhi.

DR. GOVIER: I wonder if you would mind going back and elaborating on line 4 the Estimated Productive Area?

A Yes, sir. Those areas shown for the Delhi area or the Delhi portion of the Cessford area, were determined by planimetering the properties on --

A (Cont'd) the anomolies shown on Page 6. Those areas were determined from -- in this case probable and possible areas -- were determined from use of the electrical log examinations with the seismic data which Canadian-Delhi supplied.

Assuming that the gas-water contact was in the base of the zone as penetrated -- although no water was obtained in the particular well shown, namely, Canadian-Delhi No. 3, we took the seismic dip to determine our outer limit, the so-called possible line zero. We haven't shown proved reserves to that, because the sand wasn't tested in that particular well, but it is structurally high enough in relationship to the Amerada area; from the electrical logs, it would appear likely there are reserves,but --

MR. SMITH: Could that information be made an exhibit?

A I suspect it could; I have a photostatic copy of it which I wasn't able to produce, it is subject to their release.

MR. SMITH: It might be as well to have it.

A We haven't shown any proved reserves for the Delhi-Cessford Area in the Viking. However, we show proved reserves in the Sunnynook area for the two Amerada wells. We have made special tests in the Viking.

Our factors -- the bottom hole pressure factor is estimated as 230 Psia; again yielding a recovery of gas in place in the order of between 80 and 90%.

The openflow capacity of the wells, we have no idea what that might be. They might be low

A (Cont'd) enough so that the flow rates might be of a very low order of magnitude; but in the Amerada Wells, the Viking Sand in the Sunnynook area would indicate that some high capacity wells could be developed, in the order of 15 to 25 million cubic feet per day openflow capacity.

The temperature factor was derived from the gradients in the Princess area where there were a number of measurements -- that is immediately south of Cessford and corresponds to the Sunburst Sands district in the Delhi-Sunburst No. 1 Well.

Deviation factors -- compressibility factors at initial and terminal conditions -- down at Lines 12 and 13 -- were derived from a series of curves we have relating to temperature and pressure with compressibility. We have checked that many times with gas analyses and have found that they correspond very well. As a matter of fact, it may be better since one analysis may not be actually representative of the entire field. We would prefer to use more average data. Applying those factors in the volumetric calculation, we obtained the volumes shown in lines 14 and 15 of the initial gas in place per Acre-Foot and the remaining gas in place per Acre-Foot at terminal pressure, of 469 Mcf and 91 Mcf respectively.

Those factors applied to the estimated reservoir volume in line 6, yield the quantities in lines 16 and 17, the initial and remaining volumes of gas in place under those conditions.

The subtraction of any production would

A (Cont'd) yield the quantity in line 20, remaining recoverable gas to terminal pressure.

We have added the estimated field and fuel uses in line 21, and we have estimated five wells require 64 million cubic feet of drilling gas. That included gas for compression at 4% of the gas in line 20, remaining recoverable gas, and miscellaneous waste of testing gas at 1%; and shrinkage losses at 2%; and we have deducted those quantities to yield 23, the estimated recoverable gas reserve available for sale.

MR. SMITH: Have you the total deductions in percentage, by any chance?

A It would be slightly in excess of 7%, yes slightly in excess of 7%, between 7 and 8 including the drilling gas.

The Upper Blairmore zone is shown -- the distribution and thickness is shown on the isopachous map, page 7.

This sand is well developed in the Amerada Wells and the Canadian-Delhi Wells and occurs at approximately 3150 feet.

The core data of the Canadian-Delhi Cessford No. 2 Well, and the electrical logs of all the wells were utilized in determining thickness and porosity.

Again our concept of the distribution of the proved,probable or possible areas was based upon the seismic interpretations in conjunction with the thicknesses shown for the seismic dips indicated.

Actually we don't expect those to be full

A (Cont'd) closures. There are possibilities that the Upper Blairmore may be of -- a little more of a blanket sand and may not be controlled entirely by closure, but we have made the assumption they will be limited to that extent.

Although it is quite likely there may be some connection between the areas shown on Map 7, between Canadian-Delhi 2 and 3 wells, we don't think well enough of it to even indicate it as possible at this stage.

The porosity data in line 7 was derived from the core analyses and shows an average of 24.7 %.

The permeabilities appeared to be moderate in character but the flows were substantial and the porosity was high.

We assumed that the connate water saturation would be somewhat lower than the connate water saturation assigned to the Viking Sand, namely, 35%; so we used 30% in the Upper Blairmore Sand.

You are well aware, of course, that the data on connate water saturation is one of the big points in which very little data is available any place, and we don't feel that the Restored State Method in itself gives the correct answer ourselves, but this would be perhaps conservative if anything and we have so considered it.

The bottom hole pressure was calculated from the Sunburst gradient in the Cessford No. 1 Well -- the back pressure data -- 1,245 Psia as being the initial bottom hole pressure.

A (Cont'd) Again we utilized a terminal bottom hole pressure of 230Psia.

The temperature at 88 degrees is based on gradients in the area of 1.9 degrees for each hundred feet.

Deviation factors derived again from curves relating to pressure and temperature, respectively are .81 and .96 for the initial and terminal conditions.

These factors, in the volumetric computation, yielded the Mcf per Acre-Foot volumes shown in line 14 and line 15, at initial and terminal conditions.

Those factors apply to the Acre-Foot yield our volume in place and remaining recoverable to the terminal pressure.

The deductions for field and fuel uses were based upon drilling of wells utilizing 260 million cubic feet in proved and 240 million in the probable. Deductions for compressor uses are 4% and miscellaneous 1%, shrinkage 2%, and the total average percentage deduction is between 7 and 8% for fuel and field uses and miscellaneous losses.

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MR. GOODALL: Are those deductions for field use for drilling wells referring to the same wells for each zone?

A We had set up a total of 28 wells or sand completions, it could be 14 wells and 2 completions or 28 wells, deducted in that fuel however to drill 28 although it is possible less would be used if one wished to perforate in other zones. However, the two quantities were for the "proved" and "probable" areas, a total of about 500,000,000 feet for drilling uses and assuming 28 wells. It is possible that you could develop some of the lower sands along with the upper sands and less drilling fuel might be utilized. We have assumed there are going to be single zone completions and for a maximum number of wells.

The second Blairmore Sand is limited in development to the area around the Number 3 Cessford well shown on page 8 or map 8. It is a stray sand that developed above the Upper Blairmore Sand of the other wells and was tested by the Denton-Spencer people in supervising the well as being the Upper Blairmore. The Upper Blairmore that is so developed was not tested but it looks as if it would have gas saturation as it certainly is high enough structurally compared with the adjacent wells which had the Upper Blairmore Sand tested in drill stem. Since it is immediately adjacent in section to the Upper Blairmore we utilized the porosities of the Upper Blairmore Sand. Essentially the same factors follow through except for a modi-

A (Cont'd) fication in pressure due to it locally appearing higher in the section than the average of the Upper Blairmore Sand developed in the total area.

MR. GOODALL: Was this derived from the seismic map?

A Yes sir, in all cases we have used the seismic map in conjunction with thickness determination on the electro-log and in effect carried it to a hypothetical gas-water contact at zero feet thickness assuming the base of the sand was at the actual gas-water contact if such existed in the sand tested, and there were several in which the actual gas-water contact was encountered.

MR. McKINNON: Were separate seismographs taken on each sand, on each of these sands?

A No sir, it is in effect one zone, somewhere in the middle part of the lower cretaceous, to our best knowledge.

MR. McKINNON: Do you consider you can put much faith in those seismograph pictures in regard to these sands?

A Well, since our first three gas wells, one, two, three, we had them on that basis I assume there is some relationship or other.

MR. McKINNON: They were not all in the same sand, however?

A No, they are closely adjacent, and there has not been in the correlation of the electro-logs, any appreciable change in the thickness or the intervals between the various sands.

MR. GOODALL: They have also missed two wells on the seismic?

A Yes sir, we are slightly ahead, several of those

A (Cont'd) we felt, however, had some possibilities and had so indicated.

THE CHAIRMAN: Do you think you are justified in taking the same detail on large areas?

A Yes sir, to this extent, that we know that the sand, particularly the Upper Blairmore, is quite uniform in character between the three wells, its saturation appears to be uniform over the area that we have attempted to define according to those three wells. We do not expect that the "proved" and "probable" areas will come out 100%, we hope that the general diagnostation will average out in some orientation just as one could ascribe an oval around the Leduc field and average out the reservoir volume as it is later proved up. At this stage obviously we cannot define any better with the seismic.

THE CHAIRMAN: I gather then this Upper Blairmore Sand then as you describe it, your estimate as a whole for this area you have outlined here would be fairly accurate but you would not be prepared to say that the proven area that you have shown around each well is necessarily correct?

A That is correct, obviously at this stage that is all we can hope for, is a little statistical protection on this basis because more wells will undoubtedly in between develop gas in our opinion, it may bring in some areas and perhaps average out. We have a number of illustrations which we would like cite as to what has happened in the interim on some of the other fields. On the basis as determined, hit or miss, we have been lucky so far but we do

A (Cont'd) not expect to be omniscient and come out all the time, we just hope that with the data available they are reasonable estimates.

The Sunburst Sand is the lowest sand developed in the chart and the sand lying immediately above the Madison Limestone. That is shown on chart 9. The zones are restricted to the Canadian Delhi Wells, Nos. 1 and 2, and the Amerada-Stanolind Wells in the centre of the Sunnynook area. Two wells are completed in that sand. Core analyses available on the Number 1 Cessford yielded an average porosity of 17% which corresponds very closely with the Sunburst porosity in the Princess area. The connate water saturation we have increased to 35%, we have lower porosity and apparently some average lower permeability than in the Upper Blairmore Sand. The back pressure was, the bottom hole pressure at initial conditions is derived from the calculations from the shut-in well-head pressure of the Cessford Number 1 Well completed in the Sunburst Sand, based on the back pressure tests, 1,339 pounds per square inch absolute. The terminal bottom hole pressure of 250 pounds per square inch absolute is assumed, somewhat higher than in the shallower sands which had higher porosities and possibly slightly higher permeabilities. The temperature data again comes from the gradient in the region. Deviation factors or compressibility factors from the curve relating to gravity, pressure and temperature. Those factors in the volumetric calculation yielded a gas in place

A (Cont'd) per acre foot and remaining gas in place to the terminal pressure per acre foot. The field and fuel uses, again based upon drilling approximately 13 wells, a total of 460,000,000 cubic feet of drilling fuel, compressor fuel at 4%, miscellaneous at 1%, and shrinkage at 2%; those being deducted from the remaining recoverable gas to the terminal pressure, line 20, for the various categories. The Sunnynook area surrounding the Amerada wells, the data is shown on page 5, the Viking sand is proved up from substantial tests. The most recent well, the Amerada-Crown Well, the northernmost well shown on page 6, tested four to five million a day with a very small draw-down on a very high operating back pressure, indicating a very substantial well. Most of the factors were taken from the Delhi area where core data was available in almost every instance, that is particularly for the Upper Blairmore and the Sunburst. We had originally drawn the map shown on page 6 to have the location of the Amerada-Crown Well as being just "possible". However, we were able to get enough data and with getting the electro-log by air mail and test data by air mail, modified that particular exhibit. We did not have any seismic data north of the Amerada-Stanolind Well and have just arbitrarily limited the area to the north. We were too conservative in that respect in that the Crown Well came in as a far better well as indicated by the drill-stem tests on the Amerada-Stanolind Well. The northern extent we do not know, we are perhaps

A (Cont'd) again too conservative, as a matter of fact we are limited by our base map, we pulled our limits to stay within the map. There is a distinct possibility of a rather lengthy development of good Viking sand on the basis of these two wells. The lateral extent also we cannot pin down except to the Delhi-Stanolind Well to the west in Township 26, Range 15, it did not have gas. The general trend of the developments in the Princess-Cessford area appeared to be in, that is the trend of saturation, appears to be in a northwest-southeast direction to the Province. The pressure data again was taken from the measured shut-in well-head pressures in the Delhi-Cessford area and converted by the proper radiant to the depth of the particular zones in the Sunnynook area. Our work would appear to indicate that the Sunnynook and Cessford-Delhi areas are separate, there is quite a little structural break indicated between the two. The Viking is developed at a lower sub-c depth in the margin wells than in the Delhi wells. We do not think that the development of the Viking in the Amerada wells will extend any further southwestward-south-eastward. The remaining factors again are derived, with respect to compressibility, from our curve and a check against analyses on occasion. The field and fuel uses, estimated total of 14 wells for development, two present completions, drilling fuel totals 216,000,000 feet and compressor fuel at 4%, miscellaneous at 1%, shrinkage again at 2%. The gases are rather dry and there may be very

A (Cont'd) little shrinkage if at all, that may be excessive. The Lower Blairmore Sand indicated as being gas-bearing in the Cessford area. The factors, porosity and connate water were derived from the Delhi-Cessford Wells for that same sand. We utilized again approximately the same deductions for fuel and compression and shrinkage. Generally the same pattern of data holds for the Sunburst Sands. We used the porosities developed in core data on Delhi wells and calculated the bottom hole pressure from the gradient in the area. The mechanics of the calculation in obtaining the compressibility factors were the same. We are very much of the opinion that the area shown for the Amerada wells may be low, particularly in the Viking.

MR. GOODALL: I don't think I am quite clear yet on this distinction between the Sunnynook and other Delhi wells, the Amerada wells that are at Sunnynook--

A Yes?

MR. GOODALL: Your Viking and Upper Blairmore and Sunburst Sands were all found productive in the Sunnynook and Amerada wells?

A Yes sir.

The performance calculations are shown on pages 10 and 11 following the maps. We made a composite performance calculation for the Viking Sand for both areas and the lower cretaceous sands for both areas. The slightly greater precision which might ensue by calculating each separately I do not think can be substantiated by the data

A (Cont'd) available. We weighted the factors with our best knowledge in a reasonable manner to give the various areas and their characteristics, their proper proportions in the composite performance schedules. The Viking sands shown on page 10, we handled the weighting to obtain a weighted average wellhead reservoir pressure for the Viking sands in both areas by weighting the calculated bottom hole pressures by their reserves for the areas, the fact that they would participate in the average pressure as a function of their depletion which would be a function of their reserves. That weighting for example, the Sunnynook area bottom hole pressure was 1,245 psia; the Delhi area, 1,047 psia; weighting those by their reserves we obtained a reserve weighted average initial wellhead reservoir pressure of 1,141 psia.

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A (Cont.) The Delhi area, 1,047. Weighting those by their reserves we obtained a reserve weighted average initial well-head reservoir pressure of 1,141 pounds per square inch. The deviation of the actual pressures from that, we didn't feel that it would be significant in the weighted average over the calculations we have set up. We assumed a number of wells to be developed on the basis of a thousand acres per well in Viking, the spacing can be closer, but this will give some flexibility with respect to obtaining increased deliverability later in life if the economics warranted drilling extra wells. In field drilling the definity of test for estimating what the open flow capacity in Viking Sand would be is based primarily on the Amerada well F 41 and 5, which is the Crown well, the northern most, in which a flow of 4,750 Mcf per day was gauged with a 1,065 pounds well-head flowing pressure. In effect then, a something less than a 200 pound drop between the well-head reservoir pressure and the operating pressure yielded a flow of 4¾ MMcf per day, a very substantial well, not to the extent that that might represent a stablized flow, in fact, we are quite sure it doesn't, probably will be of short duration. We roughly calculated a back pressure potential and reduced that down to have the well somewhere in the order of about 15 MMcf per day as being indicated.

In addition there was a test on the Amerada Stanolind well, the southern most well, of 2 MMcf per day on the drill stem test. We estimated this open flow to be in the order of 4 MMcf per day. We

A (Cont.) then divided the area there roughly in half and assumed that we could obtain our best judgment of a weighted average open flow by saying that we would have eight wells of about 12 million and seven of 3 million, less than the average of either of the wells on which we have some data, to obtain for the area to be developed about 8 million per day open flow well. That's in the Sunnynook area. We don't feel that the probable Viking Sand wells that could be developed in the Delhi area are going to be nearly that good, that an open flow capacity of 2 million a day would perhaps be representative, based on the thinness of the sand and its electrical log characteristics, so that for the combined area we utilized in our calculations a 7.3 MMcf per day well, hoping that we had taken into account reasonably the probable variation in order to obtain some estimate of projecting performance.

This 7.3 MMcf per day average well was then plotted as a back pressure curve having a .85 slope with the P sub.c of 1,141 pounds per square inch absolute well-head. The weighted average well-head pressure is derived as previously described from the calculated bottom hole pressures and weighted by reserves. We then obtained the usual pressure bottom factor using the well-head reservoir pressure and the reserves in place and obtained a depletion factor for the decline of open flow capacity for the depletion of the reservoir by production. Then utilizing that factor in the curves we then proceeded to drill up the area at a relatively slow rate, perhaps slower than would be indicated, as we look back on

A (Cont.) it, since it was owned substantially by Canadian Delhi and they might desire revenue a little earlier than we have indicated. The first full year of operations we estimated three wells, and six and nine, then twelve, then fifteen. Most of these wells could be drilled with a substantial drilling campaign, in half that time. However, again, we don't wish to have too optimistic a picture, not pressing either the development rate or the character of the wells to a maximum. Utilizing that drilling program with the characteristic of the wells previously estimated, we proceed to produce the gross required gas and determine the decline and open flow capacity and the decline in the delivery capacity of those wells against 813 pounds until the eighth year, which by footnote (B) we would reduce the line pressure to 713 pounds per square inch and so on through the life in order to maintain delivery. In all cases, obviously, there is some very substantial delivery capacity remaining for meeting peak deliveries if your line operating pressure were dropped and the lower pressure made up by additional compression at the trunk gathering line stations or at the main station. The percentage of total open flow capacity represented by the average daily rate shown in column 5 through the years starts out, first year at about 20% with three wells. In the eighth approximately 17%, tenth 21%, fifteenth 29%. That's just before we drop the line pressure. The twenty-first year is 23%, twenty-fifth year 19%. The daily average net gas delivery over the entire 25 year

A (Cont.) period, if we do assume that it was equally distributed, would be about six and a half million feet per day. You will note on page 10 that the actual delivery would vary as most actual operating fields build up the maximum and then decline with decline of reservoir pressure and that's a decline in delivery capacity. That is faster than is usually the decline in the operating line pressure due to the influence of new fields or higher pressure fields in the gathering system.

The same type of analyses was performed for the Lower Cretaceous sands shown on page 11, in which again we weighted the well-head pressures of various areas by their reserves in an attempt to arrive at a composite performance. In this case the range in initial pressures was from 1150 to 1339 pounds. Our weighted average was 1200 pounds. We estimated the completion of approximately 48 wells in the Lower Cretaceous Sands. Delhi-Cessford No. 1 completed in the Sunburst, most Lower Cretaceous Sand was drill stem tested at 5.1 MMcf per day, and then completed through perforations with a back pressure open flow capacity of 5.5 MMcf per day.

The lower of the curves isn't all what it should be, it is higher than .85. You will note that the distribution of the base points was such that the .85 slope drawn through the largest open flow, largest delivery volume would yield about a 5 million well, but the working pressure of 220 pounds built up within an hour and a quarter to the highest shut-in well-head pressure, indicating a very substantial

A (Cont.) permeability.

We feel that these tests, which was taken during winter time with some hydrate problems, probably are not representative. We are of the opinion that from re-examination of that data, that somewhere in the neighborhood of an 8 million a day well is not unreasonable. We hope there will be a retesting of that well and the cleaning up of the well in better weather in order to get an adequate test.

No. 2 Cessford well of Delhi had a 4 million back pressure test with severe hydrate trouble. For a given pressure drop, the volume calculated, if there was any substantial amount of hydrates in the prover, would be a lower actual volume than would have come through the prover under better operating conditions. So in our attempt to get a reasonable performance figure we have assumed five wells at 8 million per day; four small wells on the order of 1 MMcf per day in the Sunnynook area; seven wells at 6 MMcf per day, or the average of about 5 MMcf per day per well, which approximate closely those tests shown for the two tests of wells.

Q DR. GOVIER: What did you say the average was?

A 5 MMcf per day. That's for the Sunburst Sands.

Making that calculation for the Upper Blairmore Sands, we went through the same type of procedure and drill stem tested, and comparing the Blairmore with the Sunburst, the sands are better developed, have higher porosities, and we assume, higher permeabilities, that probably the 6 MMcf per day for the Upper Blairmore Sands isn't unreasonable. We wound up then

A (Cont.) weighting the Upper Blairmore and Sunburst sands over both areas with an average completion, that is, an average sand completion in the Lower Cretaceous, as being a 4 million well, and that a 4 million well becomes the basis for constructing our performance curve. .85 slope at the weighted well-head reservoir pressure of 1200 pounds per square inch absolute.

We have, we think sufficiently watered down the test data by the edgy characteristics of the sands in that area by that 4 million average well to be a realistic figure and not excessive in any respect.

Proceeding with the calculations and the performances shown on Sheet 11, we have under column 7 a total of ten wells in the first year, building up to 48 wells by the fifth year. Those, I should say, are not wells, but rather sand completions, the Sunburst and the Upper Blairmore were perforated, the same well, we don't know how that would be carried on.

The effect then of completing these wells and taking the gas out at the rate shown under column 3, the estimated required annual gross gas yield, the daily net average gas delivery in column 5 indicated that the percentage of total open flow capacity is around 21% in the first year, that's the production rate, indicated a rate of 21.6% of the total open flow capacity. The fifth year is 24%, and the average over the ten year, or thirty, at which time we would drop the line pressure. We continue along pretty close at the 25% open flow capacity, not feeling it

A (Cont.) warranted to calculate too closely ten years or fifteen years from today just how that would work out. The total average net gas delivery over a 25 year period, if smoothed out, would be in effect approximately 21 MMcf per day, ranging up to a maximum of 35 MMcf per day in the sixth year. We would anticipate some slight loss of wells in the later years by some possible slight water encroachment in the Upper Blairmore Sand which is a gas-water contact development. The 25% of open flow restriction we have followed fairly closely, although our own viewpoint is like that of Doctor Brokaw that the differential is more important consideration than any arbitrary percentage.

Q DR. GOVIER: In that connection, when you speak of a percentage of the open flow, I take it you are speaking of a percentage on Column 9, which is a well-head rather than a sand face open flow?

A Yes, in all cases that is true. That's one thing I got balled up on Monday, what that ninth column did represent, well-head or bottom hole, until I checked the notes to see what our calculations were.

I believe that covers Cessford.

(At this point the Hearing stood adjourned for fifteen minutes and reconvenes.)

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MR. DOUGHERTY: If you will refer to Census Division Ten-- I believe in the second volume -- yes -- to pages 3 and 4, which represent the data on the Viking-Kinsella: we haven't introduced any availability state on Viking-Kinsella, but have limited ourselves to the proposed gas supply fields, with the exception of the Pakowki Lake area in which our calculations were already made prior to the granting of the export certificate to Montana.

Our basic concept with regard to proved area -- really proved and probable altogether -- in the Viking field was based upon an examination of all of the sample descriptions and electrical logs which we were able to obtain upon the field, and the notes of Mr. Leisemer, as well as the testimony produced by Mr. Ralph Davis and others with respect to Viking-Kinsella, and we were convinced from examination of the logs and drill-stem test data that the area of saturation in the Viking Sand was substantially larger than indicated by most of the geologists who had presented testimony; so we drew two possible limit lines shown on page 4, which represents as best we could determine, the extent of indicated saturation of gas irrespective of the thickness of the sand. We realize that the sand will be thin toward the edges, but the permeabilities in the Viking sand are surprisingly high. From some core analyses we have seen That the migration of gas from these outer areas may be an appreciable factor in the not too distant future.

I might make a remark upon one of the big

MR. DOUGHERTY: (Cont'd) gas fields in the United States in which that very feature is now becoming evident: the Panhandle Field. A certain portion of the field is now down to about 80 pounds well-head from the original 440 pounds well-head. The pressure decline curves have been more or less straight line until this year they were starting to flatten appreciably; so much so that our estimates of reserves are now having to be reworked. There appears to be an additional increment of gas that is going to hold up the pressures at that stage and from then on down to the 15 pounds which we consider to be our depletion pressure. We are not too sure what this phenomenon is from. It may be a combination of migration from outside areas as well as loss of some wells with increased effective drainage factors for the remaining wells. At any rate, we feel it is impossible to ignore the thin areas in large areas such as the Viking.

The isopachous map 4 shows the range in what we consider to be net thickness, from a maximum of about 23 feet down to a foot or two in the outside areas.

We have included within the Viking-Kinsella, the Texas Company's Ranfurly Well, which is a more or less isolated well in township 50, north, range 12, west, which on drillstem test of the interval 2063 to 2111 feet yielded 6980 Mcf per day.

We checked some adjacent so-called dry holes and found that there were appreciable showings of gas, not much, but indicating very likely a

MR. DOUGHERTY: (Cont'd) density of gas saturation.

The intervening formation might not necessarily yield a hundred percent commercial wells, but the saturation might be produced from such commercial wells as could be drilled.

Also within the limits of the field we showed two wells in the vicinity of Manville and Claysmore to the northeast of the centre portion of Viking-Kinsella, in which one well, the northeasternmost well or Claysmore Well, drill-stem tested two million cubic feet a day from approximately three or four feet of net sand based on electrical log interpretation.

We have therefore considered those areas as essentially part of the total field area, but have limited the proved reserves to the restricted areas immediately adjacent.

The factors utilized in the volumetric calculation were based upon our interpretation of the core data collected by Mr. Leisemer,and others submitted by Mr. Ralph Davis; and we came out with a slightly different viewpoint with respect to the porosity and connate water for the thicknesses we determined. Checking with those wells which were cored and on which we did electrical logs, we arrived at 20% as a fairly average porosity for the proved area. We took the connate water determinations made on several wells and attempted to plot their relationship to permeability and porosity rather than taking just an arithmetic average, and in that respect we came out with 45% connate water

MR. DOUGHERTY:(Cont'd) for the average porosity and average permeability indicated.

If I may have a moment I will attempt to run down those figures.

All of the core samples which we were able to obtain measurements on from the various records that also had their permeability determined, had an average of 23.3%, and the average was 348 millidarcies. I don't expect our data was exhaustive but it was all we had and covered a fairly wide range of analyses and a good distribution through the field.

There were connate water determinations on a number of samples examined; so we applied the connate water percent determined by the Restored State Method against permeability in millidarcies, to see what the distribution was and the range; and since we had included some of the thin sands and edgier areas, we checked through all the permeability tests and found at about 50 millidarcies 20% porosity was about average. Connate water saturation corresponding to the 50 millidarcies, or in that range on this crude chart, is between 30 and 50%.

Not knowing exactly how shallow some of these thin sands might be, we took from that basis 45% as being our judgment of the connate water saturation for the porosity we have utilized for that net thickness, for the net thicknesses determined.

The pressure data was derived from the measured well-head pressure. Initially the Ranfurly Well recorded a pressure as high as the

MR. DOUGHERTY (Cont'd): earliest recorded sheet in well-head pressures of the early wells. The bottom hole pressure was determined at 810 Psia, which appears on line 9, Page 3.

The deviation factors, these compressibility factors again, were taken from our curves relating gravity of gas and temperature and pressure. We had measured temperatures from some of the data submitted by Mr. Davis and Mr. Leisemer.

We then calculated the total initial gas in place per Acre-Foot, 292 Mcf, and the remaining gas in place per Acre-Foot at terminal pressure, 49 Mcf.

For our area of 518,000 - odd acres, average thickness of 8.7 feet, and 4,535,000 - odd Acre-Feet, the initial recoverable reserve in place at the terminal pressure was 1 trillion, 102 billion and 57 million cubic feet for the proved area.

The amount of the possible area on that basis, on the basis of the same factors, indicated 241 billion cubic feet -- from the extensive possible area.

The total initial recoverable gas to terminal pressure, then, would be 1 trillion, 343 billion, 101 million cubic feet.

Subtracting the estimated cumulative production to January, 1951, of 151 billion, 464 million cubic feet, the remaining recoverable gas to terminal pressure of the proved area would be 950 billion, 593 million cubic feet.

The estimated field and fuel uses amount

MR. DOUGHERTY: (Cont'd) The estimated field and fuel uses amount to 114 billion, 114 million cubic feet, and that was based upon the losses and waste indicated in the statistics on production accumulated by Mr. Leisemer in his notebooks. We think that is very high and perhaps can be improved, but we thought the current losses would be reasonable to deduct for the future, even though perhaps excessive, depending on operations.

Then we deducted also 19 billion - odd feet of shrinkage losses at 2%, which may be excessive in view of the leanness of the natural gas.

MEMBERS OF THE BOARD EXAMINE THE WITNESS:

Q MR. GOODALL: Have you got the estimated field and fuel uses worked out to percentage?

A I thought I had,but I believe it came just practically as a proportion of their production -- I don't see it in my notes although I am sure it is here somewhere. It would be approximately 12% or 11% -- on that order.

DR. GOVIER: It seems to be exactly 12%.

A The estimated recoverable gas reserve, then, available for sale, after these deductions, in the proved area: 817 billion, 467 million cubic feet. From the possible area, provided it were economic at some stage to develop it, would be 207 billion, 289 million cubic feet. Now, some portion of that volume might accrue and probably would accrue to the proved area by drainage.

I believe that covers our general analyses of the Viking-Kinsella field.

THE CHAIRMAN: You will be preparing an availability schedule?

A We have made several trial runs which we don't think enough of to put out. We don't attempt at this stage to estimate availability of any other than the proposed gas supply fields. However, time provided, we are willing to take a crack at it.

THE CHAIRMAN: These fields will all have to be done. Provincial requirements will have to be considered.

Q MR. GOODALL: In the Viking-Kinsella field I noticed that you have that Manville well in here, too, in the proven area. Is there any recovery of gas from that well?

A I will have to check the log on that.

Q MR. GOODALL: I thought that was a dud.

A I believe they had some small saturation. It wasn't a well which would be commercially produced, but it would indicate saturation to a very slight thickness of a half foot or a foot. We weren't quite sure where the top was, but it was perforated and had some gas according to our records. That is the well immediately by the townsite?

Q MR. GOODALL: Yes.

A I think it was a very small volume showing that there was saturation. Perhaps one of my engineers could run that down for us and explain that, if it shows.

Q DR. GOVIER: Would you mind going over again how you arrived at the outline of the proven area for Viking-Kinsella?

A We took that figure of that limit as being approximately, plus or minus three or four feet of net gas sand. We didn't contour on close intervals, but we stayed within or close to the three foot net as indicated, that is, between two and three feet of net effective sand, determined on such wells as we could on control there. In some cases where the sand appeared to be pretty tight and was of a little greater thickness we put in that possible area; for example, one well in township 47, range 8 appeared to have eight feet of sand which was tight or low permeability. So, we eliminated those areas of sand development which we estimated to be less than three feet in thickness, since there were substantial flows on some wells within the area, currently producing, and having thicknesses of four to five feet, and we thought that saturation would certainly be available either by drilling wells or by drainage,from current wells.

We had spotted on some of our work maps our estimate of future wells and where they would be spotted in an attempt to make an availability study. We spotted a number of these wells on the edge areas as an attempt to formulate in our own minds the drainage pattern which would allow that gas to be recovered.

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DR. GOVIER: Did you make any study of pressure of some of the Delhi wells to see whether that tended to confirm your idea that the field extended considerably further than other estimators had indicated?

A We made several isobaric maps, we did not draft any of them up, time did not permit us to make any material balance studies as far as we would have liked. We plotted up the bottom hole pressure as of the middle of 1950 which is the latest recorded pressures we had and the edge wells, for example, producing in Township 49, Range 9, was 780 pounds, the original bottom hole pressure was 810 pounds. There has been some production and we, of course, could not determine whether that pressure had been upheld by migration or the depletion has been relatively slight. At any rate, as you go out from the developed area where the heavy production has taken place we find there was a fairly uniform gradient towards, which eventually almost transmitted original pressure within the limits of our "proved" area so that we felt there is virgin gas territory within the limits of commercial utility. Ranfurly, for example, came in at 810 pounds virgin pressure, it is within 8 miles of wells having a pressure of 523 pounds. We ran into difficulties attempting to get our gradient which was one reason we have not introduced these pressure maps, although I suspect they are not unlike other fields in which the gradients are always steeper than we think. If we had adequate well control, depletion has not gone out laterally as far as it would normally be expected by limited scattered points.

A (Cont'd) I have noted that in a number of limestone fields and sandstone fields also.

DR. GOVIER: Do you intend to carry out a material balance study using weighted pressures to confirm this?

A Yes, we would like to within the limits of time we have available, to attempt to make some as of about 1950 if we can adjust the gradient to our satisfaction and calculate the depletion as a correlation with our volumetric methods very much like we tried to do with Bow Island and Medicine Hat to see if we are dealing with the same order of magnitude.

DR. GOVIER: That would be very helpful to the Board, Mr. Dougherty, if you can do that.

A We will do that. Referring to Mr. Goodall's question, we have a note on the Manville well that it perforated at numerous horizons and had an open flow of 11 Mcf. On that basis we thought there was some saturation some place but we did not attach too much attention to it. However, that limit was proved saturation.

MR. SMITH: I don't know whether Mr. Goodall will withdraw that remark about "dud" or not?

A Well, Mr. Goodall may well be correct because if they have perforated at numerous places we are not too sure where the gas came from except there is some in that vicinity of very slight importance.

The Leduc field is in Division 11 pages, beginning at page 30 and continuing to page 41. The voluminous character of this particular field is attributed to Mr. Porter's interest in reefs, and I objected strenuously at times to the number of

A (Cont'd) maps but they came out to be so pretty when colored that I have more or less taken back all my remarks. We found that running down the detail on the cretaceous sands in the Leduc zone was a considerable chore. However, the system we followed was to take every drill-stem test since we have all of the well completion cards and all the electrical logs and had some engineering assistants write down all the effective and negative drill-stem tests in the Viking and lower cretaceous. We then plotted those results on a map to work on, about the size of the wall map, and unfortunately we did not bring that map with us. I regret that. However, I do have the tabulation of drill-stem tests. From those and the electrical logs we constructed the isobaric maps shown, first on the Viking as Map 31, in which most of the area we considered as only "possible" and did not assign any reserves in view of the performance of that more or less infamous Viking well in Leduc, and restricted the "proved" and "probable" areas to those areas where we could obtain very substantial drill-stem tests. There were a number of those in Township 50, West 26, no -- 50 North and 26 West, there were several tests which ran from two million eight to three or four million open flow; and 50 West, 26 West, and some Imperial wells, number 167, had some substantial gas volume, Imperial No. 1 Leduc, Imperial No 171 Leduc, Imperial No. 172, and Imperial 288 -- I beg your pardon -- let's scratch those beginning with the wells in 50, 26, -- those

A (Cont'd) happen to be Blairmore, I slipped up on the column here. The positive Viking tests were Imperial No. 10 Leduc, Imperial No.3, Imperial No. 80, Imperial No. 136, Imperial No. 4, Anglo-Canadian No. 1 in North Woodbend, Anglo-Canadian No. 3, No. 4, No. 8. Those in general define the "proved" area and the immediately adjacent "probable" areas in electro-log characteristics appear to be very similar to the "proved" areas, or where we had the smaller drill-stem tests.

The Blairmore distribution, which is Map No. 35, that is Lower Blairmore, and Map 34 which is the Upper Blairmore, were derived, those areas were derived in the same fashion by very considerably larger number of good positive drill-stem tests in the lower cretaceous which had substantially larger volume than indicated for any of the Viking sands, they are something on the order of between 25 and 30 wells which were drill-stem tested which were distributed well over the "proved" areas. We made a series of cross-sections connecting up all of the lower cretaceous Viking sands, one northwest and one southeast, and correlated the water levels and the drill-stem tests with the electro-log characteristics of those wells which there were no drill stem tests taken on or those which had very small volume or negative drill-stem tests in an attempt to define the areas as shown on Map 35. We have those cross-sections with us but it would perhaps take too much time to go into them. Isopaching

A (Cont'd) was based largely upon the electro-log and drill-stem tests, making a composite lower cretaceous thickness map. Calculations sheets for the respective sands, the Viking appears on page 30. We carefully analyzed the performance of the Imperial Leduc No. 10 completed in 1947 with an open flow of 3.3 million and its subsequent decline and relatively low volume of total production, and came to the conclusion that some restriction in the Viking reservoir was pretty well evident, low permeability in all probability as well as low porosity. The Imperial Oil Company, Mr. Bob Cot, informed us that their core indicated 15 to 16 percent for the better parts of the Viking sand. For the area we assign "proved" reserves, it was 786 acres, we utilized a porosity of 12 percent in view of the shallower character from electro-log and we have come down from the 15 to 16 percent. The connate water saturation we assumed to be as high or higher than the Viking-Kinsella field for the Viking at least as 50 percent. In view of the poor performance of that well we put the terminal bottom hole pressure at 275 psia, the initial bottom hole pressure being 1,027 psia. Those factors when applied in the volumetric formula on page 30 yielded about 645 million cubic feet for the "proved" area in the Viking and a total in the "probable" and "possible" of about 15 or 16 billion feet that might be developed over an area of something like 27,000 acres. We did not consider it to be commercial so far as taking gas except that, for some very local field uses and there will be ample for

A (Cont'd) field use gas in all probability. We, therefore, did not consider that in the proposed gas supply of Trans-Canada. We did not attempt to prognosticate the performance on the Viking.

DR GOVIER: Mr. Dougherty, would you return to the case of Imperial No. 10.

A Yes sir.

DR. GOVIER: Is it correct that that well falls within the area that you have delineated as "proven"?

A Yes, it produced gas and as such we considered it.

DR. GOVIER: What is your explanation for its rapid decline then?

A We had several ideas, a very poor reservoir, considered with connate water saturation, low permeability; and it might be local or it could be uniform for a considerable area, that is the low permeability. There were also possibilities of faulty well completion on which, not having full data, we could not go into but the drill-stem test in its initial rock-ups under pressure were fairly, would appear to have indicated some considerable permeability, but even after pulling down it did rock up to 518 pounds in 1950 so that there was slow migration in from, I suppose the outer limits or perhaps from adjacent territory since it is the only producing well; but that certainly did make us consider the Viking as questionable. However, the data in electro-logs and the cross-cuts, drill-stem tests, would appear to indicate that was no local condition, it may be fairly general.

In the lower cretaceous sands Mr. Bob Cot

A (Cont'd) informed Mr. Beach in a telephone call which he relayed to us in attempting to run down the porosity data that such core data as they had, which was rather limited, would indicate porosities on the order of 15 percent which we utilized in all our calculations. The drill-stem tests were considerably better than anything in the Viking and we have made an assumption of permeability, we have made an assumption that the permeability was undoubtedly higher and that the connate water saturation was 35 percent, which we think would not be out of line and have used that in our calculations. The pressure data was determined from a pressure gradient in the D.3 of Leduc, that is by pressure measurements in the D.3 converted to pressure gradient for the field, but that appeared to be too high, therefore we took pressure gradients indicated for the lower cretaceous in the Morinville-Excelsior area where there has been some tests and obtained a pressure of 1,260 psia. The Calahoo well had a pressure gradient which indicated .324 psia per foot of depth. The terminal bottom hole pressure was assumed as 275 psia, keeping again within our range of 75 to 85 percent recovery from the sand. Bottom hole temperature was from the Excelsior where they had measured temperatures. Compressability factors were from the curve relating gravity, temperature, and pressure. Those factors yielded 380 Mcf per acre foot in place initially. 78 Mcf per acre foot remaining in place at the terminal pressure. For field and fuel uses we assumed drilling of a total of 42 wells eventually.

A (Cont'd) However, in the "proved" area we assumed three wells in the Upper Blairmore and in the lower sands of the Blairmore a total of 44 wells. Compression losses were used again, estimated at 4%, miscellaneous losses at 1%, shrinkage at 2% or for the shallower in that sand at 3% on that lower Blairmore sand as shown by the footnotes (A) and (B) on page 33.

The proved reserves available for sale in line 23 from both the Blairmore sands total 198 billion feet, "probable" 129 billion feet, total of those categories 328 billion feet, "possible" reserves, 77 billion cubic feet; and the total of 405 billion cubic feet. The availability study or projected performance is the following page, 33(b). Again to obtain a performance curve we weighted the bottom hole pressures by, or the well-head pressures, closed-in well-head pressures, derived from bottom hole pressures, by the respective reserves in the sands to obtain a weighted closed-in well-head pressure of 1,256 psia. There are no present gas wells that we are aware of. We estimate two to be completed in the Upper Blairmore and 40 in the Lower Blairmore if the gas were obtained prior to depletion of other reservoirs at Leduc. The drill-stem tests recorded in the neighborhood of 25 to 30 of them, well distributed in the area we have designated as "Proved" and "probable", ranging up to 6MMcf per day and in the "probable" there may be some in the order of 3 to 5 million cubic feet per day.

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A (Cont.) Mr. R. Pot the Chief Reservoir Engineer for Imperial Oil seems to think the permeability is very high on the order of 2,000 to 3,000 millidarcies. That seems excessive to us, but we haven't the data to base that on. Our north-south cross section which we constructed indicated that there would be some relatively lower permeability at the north end of the field in the Woodbend section. At any rate we came to the conclusion that permeability was appreciable, and for an average we were thinking in terms of 500 to a thousand millidarcies rather than the two to three thousand millidarcies which could only have been derived from better wells. With this data in mind and realizing there were a number of limitations, we estimated the average sand completion should be on the order of 6 million per day as the well-head open flow potential. That was in the Lower Cretaceous Sands particularly. Some of that indicated Upper Cretaceous Sands at higher permeability. We wound up utilizing an 8 million average well at 1,256 pounds per square inch absolute well-head on the .85 curve. That data - - I see an error here in the notes, there is an "8" but it is plotted as a "6", so we wound up using the "6". Someone must have gotten cold feet. So it is a 6 million average well at 1,256 pounds per square inch absolute. That curve with the reservoir volume pressure factor derived from the reserve estimate led to our calculation of the performance on page 33B in which is planned ultimately to have approximately 42 sand completions in the Lower Cretaceous distributed among as many as six or

A (Cont.) eight sands which are developed in the Upper and Lower Blairmore. Column 7 shows a range from 10 to 42. 42 wells being reached in about the ninth year. The daily average net gas delivery we built up from 10 million a day initially to a maximum of 35 million a day, which didn't require the reducing of the well-head working pressure below 813 pounds until the sixteenth year. From then on the working pressure dropped in 100 pound increments at intervals. I was attempting to find the percentage of open flow capacity represented, and that starts out in the first year at 18.2%, and the sixth year it is 9.3, and the tenth year it is 7.8, and the fifteenth year 23.8, and the last five years it ranges around 30 to 35%. We have visualized the performance here to be an attempt to produce the gas over a lengthy period of time and keep the percentage take of open flow down in the early years, to add in the maintenance or meeting peak deliveries along with Morinville and Pincher Creek and the Amisk Lake area. The average indicated daily average net gas delivery over the 25 year period, if smoothed out, would be about 21,762 Mcf per day. In most of these performances calculations were wound up utlizing between 70 and 80% of the gas available for sale at the well-head through the 25 year period, leaving still some cushion for availability and for the long time haul after that time, or for enabling higher rates to be taken early in the life, due to increased drilling rates.

We didn't indicate in our calculation for utilization of any of the dissolved or associated gas

A (Cont.) in Leduc for the Trans-Canada Pipe Line, not knowing what this line would be in respect to the D3 gas cap, a long delay by any operator, and as some evidence has been introduced that such gas might be utlized for secondary recovery in other reservoirs at the later part of life. We have, however, made estimates on all these reservoirs, and they are included with in this report and subject to your desires, we could go into these. Of course, we thought at this stage, looking ahead 25 years, no one is in a position to extrapolate very well. I would rather think that eventualities would be quite difference. We will, however, prepare to the best of our ability some available studies on these other reserves and try to submit some sort of over all picture. Due to the length of time available, but in effect, what our clients program would be, that developments in the next few months are going to make some differences in the over all eventual picture.

If that suffices for Leduc, or would you care to go into - - ?

THE CHAIRMAN: We would like to know the D2 and D3, they vary quite a bit from the estimates we have been given.

A On page 36 there are estimates for the Leduc field, the D2 or Nisku reservoir, that's the dissolved gas. The following map on page 37 was a distribution map of the gross oil saturation in the Nisku or D2, that's D2 Devonian, divided into our proved and probable and possible categories. We found that the reservoir was rather uniform in thickness, and our

A (Cont.) estimate, on examination of some core data, appears to indicate that the net pay thickness was about 30 feet, plus or minus. We applied that to the proved and probable area, based on the distribution of those areas determined from the electrical logs in the possible area. Along the edge we reduced that to ten feet, since they were on the very edges, and approaching the limits of the development of oil saturation. The porosities deduction were 9%, which would seem to have been fairly uniformly accepted, but time didn't permit us to analyse almost hundreds of core analyses which were available in Leduc. To modify that, since there seems to be a fairly uniform agreement on the 9%, likewise with respect to the connate water saturation, we have initiated some material plant studies in these proved reservoirs, but I don't know when it will be completed or whether there actually is sufficient data yet to permit us to make any definitive estimate, however, that's part of our over all study. I doubt that the data would warrant that presentation this year. The permeabilities appear to represent up to 100 millidarcies on the average. The Nisku isn't a very permeable reservoir. Mr. Ted Baugh's factors were primarily utilized as being the best data available, certainly having had access to the best data. With respect to the shrinkage factor, .72, we haven't been able to obtain ourselves the actual laboratory data from any of the operators. That led to a volume factor of 1.39. A solution of gas-oil ratio of 689 again was taken from Baugh's work. Those factors were applied to the

A (Cont.) acre feet of reservoir volume, which we determine from planimetering the distribution map of the D2 and led to the estimated initial recoverable dissolved gas in place as being 240,918 MMcf. Assuming that in effect 85% of the oil, gas in solution in the oil would be recovered, that is, 100% of the gas in solution would be brought to the surface as stock tank barrels, would be recovered, but that only 80 or 85% of the residual gas in the residual oil would be recovered since we visualized this reservoir as being a depletion type reservoir without any active water-drive, and that the ultimate recovery of oil would be on the order of 20% or perhaps less of stock tank barrels in place unless secondary recovery projects it some considerable magnitude. We haven't considered that in our studies, but it is rather the amount of gas which would be obtained under a depletion type reservoir performance. As a general statement we have made the assumption that for all the known water-drive reservoirs, it is a fairly good and experienced factor in depletion reservoirs in other fields.

The cumulative production is estimated, as best we could from records, leaving remaining recoverable gas in the proved area of 201,444 MMcf. The estimated field, fuel uses and waste was put at 20%. We have too little experience to know just what the actual factor will be, but it is our viewpoint that that would be in general on the high side. If the economics would permit the gathering and processing of the gas to that extent, our estimated recoverable

A (Cont.) reserves available for sale are contingent upon the economics that will allow that waste and fuel use to be kept at a minimum. The resultant recoverable reserves available for sale would be 161 MMMcf.

We have considered that an enlargement of the Devon plant, or a second plant would be economical if the price for gas were connected preferably to a long distance transmission line, and would be a conservation matter, then an economic matter. That should be carried through, if possible, but we can't, in our own minds, project what the losses and usage is going to be until such a plant comes into existence.

The same factors were applied to the probable and possible, yielding a proved and probable available for sale reserve of 232,016 MMcf. Possible reserves is less in magnitude and almost negligible of any consideration, 10,334 MMcf.

The associated gas reservoir, that's the Leduc D3 gas cap, the calculation shown on page 38, and the Isopachous map of the gross Leduc D3 Devonian gas saturation is shown on page 39. There was abundant control for the oil reservoirs, and we feel that our Isopachous maps are in a high order of accuracy. The gas cap is very thick. Our average reservoir thickness, derived from the Isopachous maps, is 66.1 feet. The estimated productive area is 14,000 acres. The reservoir volume in acre feet is 926,064 acre feet. Again our porosity factors and the reservoir factors were primarily derived from Mr. Ted Baugh's work. A porosity of 13% and connate water saturation 12%. The permeability ranged very great, and permeability on a relatively

A (Cont.) high order of magnitude. A formation volume factor of 1.46, yielding a shrinkage factor of .685 for reservoir barrels to stock tank barrels. Solution gas-oil ratio 779 cubic feet per stock tank barrel. The gas cap was treated as gas reservoir.

Under the D3 gas cap we calculated the initial reservoir pressure from the bottom hole pressure in the D3 oil reservoir. Again, a terminal reservoir pressure of 381 pounds, which is, in effect, equivalent to a percentage recovery for the matter of these calculations. It is only an equivalent terminal pressure since we feel that the Leduc D3 reservoir will be produced under a very active water drive, that the reservoir pressure will probably never get below 1800 pounds, plus or minus, and that the net recovered gas from the gas cap will be by active water drive of high availability of gas due to the high pressure, but the net result would be a depletion corresponding to the percentage recovery of 831 pounds as a terminal pressure, relates to the initial reservoir, the initial bottom hole pressure.

The calculations carried out compressibility factors, derived again from our curves based on the analyses. The initial gas in place per acre foot 701 Mcf. Gas remaining in place at terminal pressure 118 Mcf per acre foot. The initial recoverable gas to the terminal pressure is almost 540 MMMcf. Our shrinkage, field and fuel losses and waste is estimated at 132 MMMcf, in the order of slightly over one-fifth of the gas recoverable

A (Cont.) at the well-head. The remaining recoverable gas being the difference, 408 billion feet, approximately.

The D3 Leduc dissolved gas reservoir was carried out in a manner similar to the Leduc D3 reservoir, and that appears on an unnumbered page behind page 39. That would be 40 if it were numbered. The map on number page 41 is our Isopachous map of the gross D3 oil saturation ranging from 0 up to 38 feet. That 38 foot plateau in effect being the intersection of the gas-oil interface in the total Leduc Dolomite. All above that is the gas cap saturation. Our average thickness of the acre feet is 27.6 feet in the proved area and 12.6 feet in the probable area. The average in the total proved and probable is 25.7 feet. Due to the pinched out, the thinning out on the edge of the 38 feet, that covers most of the, the 38 feet covers most of the reservoir.

The porosity again was taken from Mr. Baugh, 13%, and connate water 12%. The shrinkage factor was previously mentioned, .685. Estimated initial oil in place per acre foot at 608 barrels per acre foot in place. Initial dissolved gas-oil ratio is 779 cubic feet per stock tank barrel. We estimated a dissolved gas recovery factor of 50%. We estimated that the recovery of oil from the reservoir is going to be in the order of 40 to 55% under water drive; that 100% of the gas in the barrels brought to the surface would be recovered by flushing out, and, however, due to the water drive characteristics, that the total point would not be reached in the

A (Cont.) residual oil, and that there would be no ultimate recovery of gas from the residual oil due to the activity of the water drive, that such gas in solution in the residual oil would not be recovered, nor would that oil, except perhaps small amounts with the production of the large volume of water. On that basis then, the initial recoverable dissolved gas per acre foot is 50% of the initial dissolved gas in place per acre foot. There is total initial dissolved gas in place of 229,961 MMcf. The initial recoverable dissolved gas is 115,224 MMcf.

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A (Cont'd) Those two quantities are obtained by multiplying the respective Acre-Foot factors: 473 and 237, by their reservoir volumes.

The estimated cumulative production is 10 billion - odd feet, subtracting that to get the remaining recoverable gas of 104 billion, 649 million Mcf.

Taking the waste, fuel uses and field uses at 20%, and deducting those, results in the remaining estimated recoverable reserves available for sale of 83 billion, 720 million for the proved and 6 billion, 165 million from the probable.

I thought we had a summary sheet containing those two, but I see that doesn't appear, it isn't included here; but those two estimates stand alone, anyway.

I believe that covers Leduc.

Q DR. GOVIER: Mr. Dougherty, have you had any experience or do you know of any fields where the water-drive has been so active that the thing you say may happen here has actually happened?

A Yes, there are a number of active water-drive fields on the Gulf Coast in which the volumes of recovery stock tank barrels have been far more than we can calculate volumetrically on an Acre-Foot basis. Some of them have higher porosities and some of the figures become ridiculous, that it would be 80 or 90% of the oil in place. But when we have been able to pin down void space accurately, it isn't unusual to find 50 or 60% recovery of what our best estimate of stock tank barrels would be.

A (Cont'd) However, with respect to limestone reservoirs our experience is not that good. There have not been too many where we can definitely show 50%.

The kinds we are familiar with in west Texas don't have a high permeability or active water-drive, don't have that high permeability or water-drive indicated by the pressure history to date; except in the Ellenburger Ordivician one. We have had some experience there where recovery would be on the order of 40 to 50%.

It is certainly too early to be dogmatic on the recovery factor on these reef reservoirs. It is within the limits of possibility.

DR. GOVIER: I think you misunderstood me. I wasn't suggesting it was high. The Board's previous thought was that the recovery of solution gas would be much greater than 50%. We have been concerned over the possibility that the bubble point may never be reached if the water-drive is sufficiently active.

A Oh.

Q Do you know of any cases where the water-drive has been that active?

A Not that I know that we can be perfectly sure of; but in the estimations of that recovery of 50% in the oil, that is based on a very active water-drive and the maintenance of pressure above that bubble point.

That is our basic assumption, that there would be no mechanism -- if the water-drive is that active -- to bring that pressure down sufficiently to allow the gas to break out of the residual oil.

A (Cont'd) Again, we may be on the low side, but if the water-drive is that active the D-3 gas cap would be produced before the bubble point was reached, and none of the gas in the residual oil would get out of the solution. The D-3 gas cap would be produced before the bubble point was reached which would be approximately 1860 pounds. The bubble point would have to be reached and I don't think that is going to happen, although it might well be that some will break out if it gets below the bubble point, you see, in local areas by coning of water or reducing pressure -- I don't know.

Q DR. GOVIER: I just had one other question I wanted to ask concerning the D-3: that is, that you have used a terminal pressure of 381, and you explain that that is really the equivalent of a recovery percentage?

A Yes.

Q It seems to work out at about 80% recovery of the gas in the gas cap?

A That's right, it would be 701 -- I mean, 583 divided by 7.

Q I think it is fairly near 80%.

A Yes, 80%.

Q My question is this: from the theoretical point of view one would expect a considerably higher recovery on the assumption of a complete water-drive. It seems, therefore, in using 80% recovery factor you are taking into account some reservoir loss which cannot be protected theoretically?

A That's correct.

Q And yet previously, the other day, you intimated you thought the prudent operator would close in any wells that tended to produce water and in that way avoid any such reservoir loss. Would you comment on that?

A The difference would be that we are dealing with also an oil reservoir whereas those others were non-associated gases, and I suggest it might be difficult to get operators to close in wells producing some considerable amount of oil with the water. There will be some difference that way and probably 90% would not be realized. You might have oil and gas and water all together in the last stages.

Q Then, 20% consists of 10% due to waning pressure and 10% due to encroachment?

A Well, it's something we can't distinguish, it's something more or less out of the air at this stage.

I had sent up -- if you have a few moments-- an example or two of some places where additional wells have come into our projection of probable areas and we might like to advertise to that extent -- it will only take a few minutes.

For example, in the Acheson Field which is division 11, Page 5 is the isopachous map of the Viking net gas sand,and although we have apparently closed the southern-most reservoir, the structural picture would appear to indicate that the structure is still building up to the east. We just ran out of wells and the Viking appeared to be diminishing some in some of the wells so we arbitrarily closed it on the east side.

A (Cont'd) Since that time the Royalite people have completed their No. 2 Stony Plain Well on section 23, township 52, range 26, which lies about two miles east of Imperial's Stony Plain Well which is shown on the south tip of the proved area.

This well came in at a relatively high structural position, much like the structural map we had indicated, and drill-stem test indicated 2.27 million. So, what we pulled in due to lack of drilling on the east is to our minds substantially changed so that the area of proven saturation may be perhaps doubled or perhaps only 50% greater.

In Bashaw -- in which we haven't prepared a map -- that is in division 8 -- it was a one well field, a D-3 gas reservoir. We had arbitrarily drawn a proved and probable area around it for calculating purposes. Since we drew that, the California-Standard people tested in their No. 4-21 Spotted Lake well in section 21, township 41, range 22; another Bashaw type of well recording 5½ million of D-3 gas, two miles south of the limit we had chosen as possible around the first well; so that we could now shift our limits down or leave that as it is and say there is an addition to the south. At any rate, a substantial area is developing beyond that apparently, which we wanted to consider at that time.

In the Stettler Field the same situation occurred with respect to the Gulf location in section 15, township 38, range 20 -- the Stettler Field is in division 8 also, Census Division 8 -- I am referring

A (Cont'd) to page 14. Now -- no, 15 -- although of minor importance the Gulf Well in section 15 -- No. 9 we figured was clear out of the proved area and it came in with water in the D-3 so that our limits would not have extended that far north; so we had some negative evidence of the limits of that reservoir.

In Golden Spike, for example, in division 11, Page 15, there is a map of the cretaceous sands.

MR. SMITH: What was that last one.

MR. DOUGHERTY: I think I have misread something.

MR. SMITH: I didn't intend to indicate that.

MR. DOUGHERTY: Golden Spike, page 16; we have an isopachous map of the Viking net gas saturation, the Anglo-Calmont people completed a drill-stem test of salt water in a well on section 34, which shows to be just out of our possible limit. I don't know how we got that, but it proves that at least there is no gas to the west beyond that possible limit.

In the Blairmore, the succeeding map on that same well, which we show as in the possible-probable area -- that is the well immediately northwest of the centre of section 34, they drill-stem tested 12½ million in the Blairmore "A" sand, which would prove up that probable area.

The Gulf Well in section 34, too, which is the No.2 location down in the southeast corner of section 34, we show as just inside the proved area, came in anddrill-stem tested 5½ million in the Blairmore "A" sand.

A (Cont'd) Referring to the Picardville Well in division 14 Page 19, the Canadian-Delhi No. 2 Picardville is located in section 6 of 59 - 26, and is a northwest offset of the No. 1 well. It is in L.S.D. 11; roughly locating it it would be just outside of our proved limit, and in the probable area at an isopachous thickness of somewhere around 13 feet. The drill-stem test yesterday morning demonstrated 6.8 million cubic feet from that sand at a fairly high operating pressure, and the electric log would indicate somewhere around 10 to 12 feet, perhaps a little higher depending on the core data, so we were lucky to that extent. The northeast extension well which we considered in a probable area is now proved, and on the basis of structural data our northeast limit there is going to be fairly accurate.

MR. SMITH: What was the name of that?

A Canadian-Delhi No. 2 Picardville. There will undoubtedly be some that won't come out quite as nicely --.

DR. GOVIER: I was going to ask if you didn't have any evidence on the other side of the picture.

A Curiously enough, not yet; but no doubt there will be a considerable number. We hope they will be offset by as many the other way.

THE CHAIRMAN: I think we will adjourn to tomorrow morning.

At this point (12:59 A.M.) the hearing stood adjourned until 9:30 A.M., Thursday, the 10th day of May, A.D. 1951.

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